Technical Assistance Document

for the Louisiana State Implementation Plan for the Entergy Nelson Facility

June 2017

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Louisiana Regional Haze BART Technical Assessment Document

1 Introduction

The purpose of this Technical Assessment Document (TAD) is to provide technical and supplementary information for consideration by Louisiana in its revision to the State Implementation Plan (SIP) revision, submitted by the Louisiana Department of Environmental Quality (LDEQ) on February 10, 2017 to address BART requirements at the Entergy Nelson facility. This document does not represent EPA's final determination concerning BART for the Nelson facility. We will address LDEQ's SIP submittal for BART for the Nelson facility separately through full notice and comment rulemaking.

2 Best Available Retrofit Technology (BART)

2.1 Overview of Our Previous Proposal as it Relates to the Nelson Facility

States are required to identify all BART-eligible sources within their boundaries by utilizing the three eligibility crieteria in the BART Guidelines (70 FR 39103, 39158, March 6, 2005) and the Regional Haze regulations (40 CFR 51.301). Because Louisiana's 2008 Regional Haze SIP relied on CAIR as better than BART for EGUs, that submittal did not include a determination of which BART-eligible EGUs were subject to BART.

2.2 Information Relating to the Subject to BART Determination for Nelson

The LDEQ submitted a revised SIP submittal on February 10, 2017, that evaluates BART-eligible EGUs in the State and provides a BART determination for each such source for all visibility impairing pollutants except NO_X.

In Louisiana's initial 2008 Regional Haze SIP submittal, the LDEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART, and we approved this threshold in our previous action.[1] In our separate proposal (82 FR 22936 (May 19, 2017)), we proposed to find that the use of the same threshold is appropriate for these EGU sources. Our CAMx modeling indicates that the Nelson source has a maximum impact of 2.22 dv at Caney Creek, with 31 days out of the 365 days modeled exceeding 0.5 dv, and 9 days exceeding 1.0 dv.[2] Both CALPUFF and our CAMx modeling support the conclusion that Nelson is subject to BART.

2.3 NOx BART for the Nelson Facility

Separately, we have proposed to find that the NO_X BART requirements for EGUs in Louisiana will be satisfied by our determination, proposed for separate finalization, that Louisiana's

[1] See, 77 FR 11839, 11849 (February 28, 2012).

[2] We note that CALPUFF modeling also estimates impacts from the Nelson source to be above the threshold.

participation in CSAPR's ozone-season NO_X program is a permissible alternative to source-specific NO_X BART. 82 FR 22936 (May 19, 2017). We noted that we cannot finalize this portion of the proposed SIP approval unless and until we finalize the proposed finding that CSAPR continues to be better than BART[3] because finalization of that proposal provides the basis for Louisiana to rely on CSAPR participation as an alternative to source-specific EGU BART for NO_X.

3 Our Analysis of Louisiana's SO_2 BART Determinations for the Nelson Unit 6

Louisiana incorporated the BART analyses Entergy prepared for the Nelson Unit 6 into its SIP.[4] This analyses includes consideration of two types of SO_2 scrubbers: Spray Dryer Absorber (SDA) and wet Flue Gas Desulfurization (wet FGD), Dry Sorbent Injection (DSI), enhanced DSI, and lower sulfur coal. Below we provide our analysis of Entergy's control-cost analyses, and provide our own control cost analyses. We also address how we believe our control cost analyses addresses the BART five factors.

3.1 Identification of Technically Feasible SO_2 Control Technologies for Nelson Unit 6

Energy Information Agency (EIA) data indicates that the Nelson Unit 6 primarily burns subbituminous coal, but also burns significant quantities of Distilled Fuel Oil (DFO).[5] Available SO_2 control technologies for coal-fired EGUs consist of either pretreating the coal in order to improve its qualities, or treating the flue gas through the installation of either DSI or some type of scrubbing technology. In addition, we are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil either primarily or secondarily.[6] Consequently, we will consider the installation of various types of scrubbers to be technically feasible for either coal or fuel oil for this unit. We also will consider the use of low sulfur coal to be technically feasible for this unit.

3.1.1 Coal Pretreatment

Coal pretreatment, or upgrading, has the potential to reduce emissions by reducing the amount of coal that must be burned in order to result in the same heat input to the boiler and by reducing the

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[3] 81 FR 78954.
[4] Entergy BART Five-Factor Analysis, for the Roy S. Nelson Electric Generating Plant, prepared by Trinity Consultants, November 9, 2015, *Revised April 15, 2016*. Heareafter referred to as the "Entergy Nelson BART Analysis."
[5] See EIA Form 923, Schedules 2, 3, 4, and 5 available here: http://www.eia.gov/electricity/data/eia923/.
[6] Crespi, M. "Design of the FLOWPAC WFGD System For The Amager Power Plant." Power-Gen FGD Operating Experience, November 29, 2006, Orlando, FL.
Babcock and Wilcox. "Wet Flue Gas Desulfurization (FGD) Systems Advanced Multi-Pollutant Control Technology." See Page 4: "We have also provided systems for heavy oil and Orimulsion fuels."
DePriest, W; Gaikwad, R. "Economics of Lime and Limestone for Control of Sulfur Dioxide." See page 7: "A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0-2.0% sulfur oil."

amount of sulfur in the coal burned. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

Coal Washing

Coal washing is often described as preparation (for particular markets) or cleaning (by reducing the amount of mineral matter and/or sulphur in the product coal).[7] Washing operations are carried out mainly on bituminous and anthracitic coals, as the characteristics of subbituminous coals and lignite (brown coals) do not lend themselves to separation of mineral matter by this means, except in a few cases.[8] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[9] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place at large dedicated coal washing facilities, typically located near where the coal is mined. Consideration of coal washing as a viable SO_2 control technology presents a number of problems:

- Coal washing is not typically performed on the types of coals used in the power plants under consideration, Powder River Basin (PRB) subbituminous and Texas lignites.
- Because coal washing is not typically conducted onsite of the power plant, it is viewed as a consideration in the selection of the coal, and not as an air pollution control.
- Coal washing poses significant energy and non-air quality considerations under section 51.308(e)(1)(ii)(A) For instance, it results in the use of large quantities of water,[10] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[11]

Because of these issues, coal washing is not further considered as a potential BART control.

Coal Drying

In general, coal drying consists of reducing the moisture content of lower rank coals, thereby improving the heating value of the coal and so reducing the amount of coal that has to be

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[7] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.
[8] Ibid.
[9] Various coal washing techniques are treated in detail in Chapter 4 of *Meeting Projected Coal Production Demands in the USA, Upstream Issues, Challenges, and Strategies*, The Virginia Center for Coal and Energy Research, Virginia Polytechnic Institute and State University, contracted for by the National Commission on Energy Policy, 2008.
[10] "Water requirements for coal washing are quite variable, with estimates of roughly 20 to 40 gallons per ton of coal washed (1 to 2 gal per MMBtu) (Gleick, 1994; Lancet, 1993)." Energy Demands on Water Resources, Report to Congress on the Interdependency of Energy and Water, U.S. Department Of Energy, December 2006.
[11] Committee on Coal Waste Impoundments, Committee on Earth Resources, Board on Earth Sciences and Resources, Division on Earth and Life Studies; *Coal Waste Impoundments, Risks, Responses, and Alternatives*; National Research Council; National Academy Press, 2002.

combusted to achieve the same power, thus improving the efficiency of the boiler. In the process, certain pollutants are reduced as a result of (1) mechanical separation of mineralized sulfur (e.g., and iron pyrite) and rocks, and (2) the a result of the unit burning less coal to make the same amount of power.

Coal drying can be performed onsite, so it can be considered a potential BART control. Great River Energy has a patented process being successfully utilized at the Coal Creek facility available for installation.[12] This process utilizes excess waste heat to run trains of moving fluidized bed dryers. The process offers a number of co-benefits, such as general savings due to lower coal usage (e.g., coal cost, ash disposal), less power required to run mills and ID fans, and lower maintenance on coal handling equipment air preheaters, etc.

In general, the greatest benefit to both improving the efficiency of the boiler and in reducing pollutants is derived from the lowest rank coals. Lignites, for instance, generally have the greatest moisture content and the highest concentration of pyrites. Higher rank coals, such as Powder River Basin subbituminous, show a somewhat lower benefit.

Although we view this new patented technology as a promising path for generally improving boiler efficiency and obtaining some reduction in SO_2, its analysis presents a number of difficulties. For instance, the degree of reduction in SO_2 is dependent on a number of factors. These include (1) the quality and quantity of the waste heat available at the unit, (2) the type of coal being dried (amount of bound sulfur, i.e., pyrites, moisture content), and (3) the design of the boiler (e.g., limits to steam temperatures, which can decrease due to the reduced flue gas flow through the convective pass of the boiler). Because we lack the necessary operating information for this new technology, we cannot assess many of these issues at this time. Therefore, coal drying is not further considered as a potential BART control.

3.1.2 Dry Sorbent Injection

Dry Sorbent Injection (DSI) is performed by injecting a dry reagent into the hot flue gas, which subsequently chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate device. A blower is used to deliver the sorbent from its storage silos through piping directly to the flue gas ducting via injection lances. The most commonly used sorbent is trona, a naturally occurring mineral primarily mined from the Green River Formation in Wyoming. Trona can also be processed into sodium bicarbonate, which is more reactive with SO_2 than trona, but more expensive. Hydrated lime is another potential sorbent but it is less frequently used and little data is available regarding its potential performance and cost. In general, trona is considered the most cost effective of the sorbents for SO_2 removal. There are many examples of DSI being used on coal fired EGUs to control SO_2. However, DSI may not be technically feasible at every coal fired EGU. We are unaware that the Nelson Unit 6 has any technical limitation on the use of DSI. Therefore, at this time we believe DSI is a technically feasible control option for this unit.

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[12] DryFining™ is the company's name for the process. It is described here: http://www.powermag.com/improve-plant-efficiency-and-reduce-co2-emissions-when-firing-high-moisture-coals/

3.1.3 SO_2 Scrubbing Systems

In contrast to DSI, SO_2 scrubbing techniques utilize a large dedicated vessel in which the chemical reaction between the sorbent and SO_2 takes place either completely or in large part. Also in contrast to DSI systems, SO_2 scrubbers add water to the sorbent when introduced to the flue gas. The two predominant types of SO_2 scrubbing employed at coal fired EGUs are wet Flue Gas Desulfurization (wet FGD), and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. Babcock and Wilcox provides a summary comparison of the technologies: [13]

Wet FGD systems provide the highest levels of SO_2 control (up to 99%) at generally the lowest unit operating costs for high sulfur applications. However, they typically have the highest initial capital costs. They are applicable to coals of all sulfur content and systems are available to generate usable byproducts for sale. They are the most frequently applied technology for new coal-fired capacity outside of the United States. Wet FGD systems include wet spray tower scrubbers and tray tower wet scrubbers.

SDA and CDS systems are frequently utilized for medium and low sulfur coal applications where lower removal efficiencies of 90 to 98% are required to achieve the desired emission targets. These systems have lowest·initial capital costs and simpler process and control steps than wet FGD systems. They use less water and auxiliary power, and the end product is dry for easier use or disposal. However, spent reagent reuse remains limited in the U.S. The need for wastewater treatment is eliminated and the FGD processes can be used to consume plant wastewater streams. An SDA or CDS scrubber retrofit typically includes a new or upgraded fabric filter which provides an opportunity for reducing filterable and total particulate matter emissions. For smaller utility and industrial applications, the simplicity in process and design has enabled semi-dry technologies to be used in higher sulfur coal applications.

The Energy Information Administration reports[14] the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 1. EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber (SDA)	269

[13] Babcock and Wilcox. *Steam, Its Generation and Use*. Forty-second edition, 2015. Chapter 34.

[14] See EIA-860 data available here: http://www.eia.gov/electricity/data/eia860/index.html. EIA states in the "FGD" tab of the "EnviroEquip_Y2015_Early_Release.xlsx" file that plants with combustible-fueled steam-electric generators with a sum of 10 MW or more steam-electric nameplate capacity (including combined cycle steam-electric generators with duct firing) are required to report information about their flue gas desulfurization units. (These plants are designated as Steam Plant Types 1 and 2). Some plants that are neither Steam Plant Type 1 or 2 have voluntarily reported flue gas desulfurization unit information; this voluntarily reported information is also displayed.

Circulating dry scrubber (CDS)	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
Dry Sorbent Injection (DSI)	106
Other	1
Unspecified	1
Total	854

Excluding the DSI installations, EIA lists 748 SO_2 scrubber installations in operation in 2015. Of these, 296 are listed as being spray type wet scrubbers, with an additional 42 listed as being tray type wet scrubbers.[15] An additional 269 are listed as being spray dry absorber types. Consequently, spray type or tray type wet scrubbers (wet FGD) account for approximately 45% of all scrubber systems, and spray dry scrubbers (SDA) account for approximately 36% of all scrubber systems that were operational in the U.S. in 2015.

Some of the other scrubber system types (e.g., venturi and packed wet scrubber types) are usually considered to be older, outdated technologies and will not be considered in our BART analysis. Jet bubbling reactors and circulating dry scrubbers are relatively new technologies, with limited installations, and little information is available with which to characterize them. Therefore, they will not be further considered as BART controls.

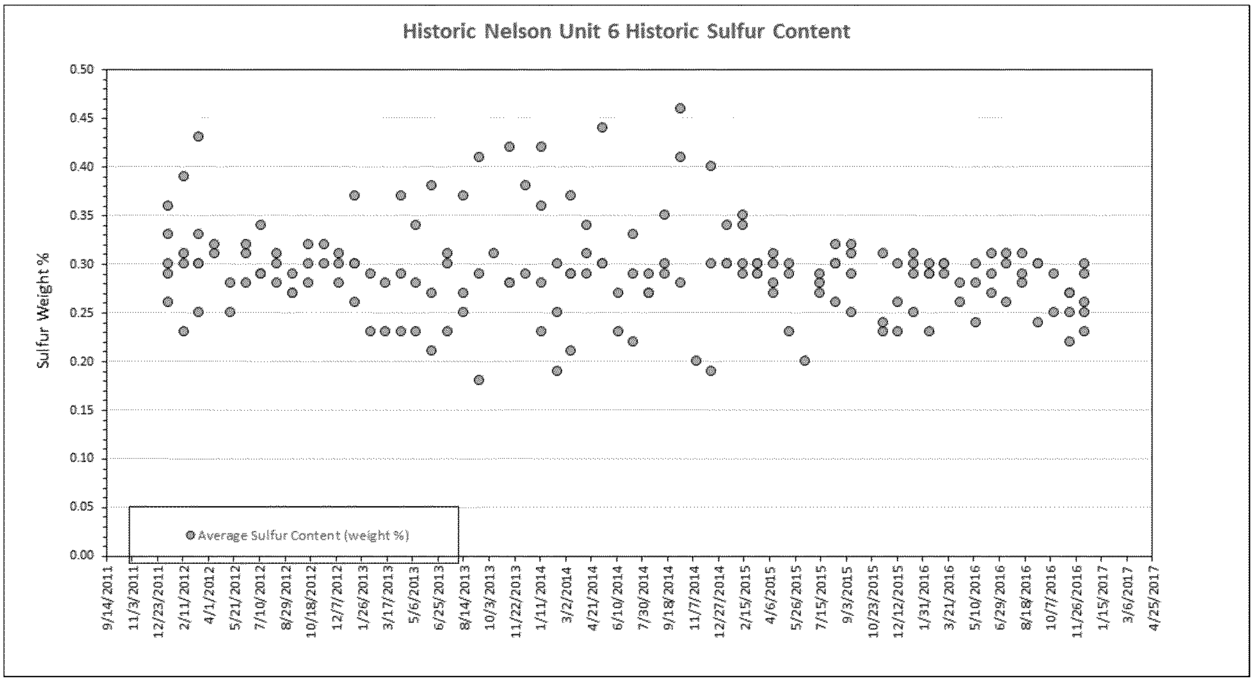
In summary, we believe limestone wet FGD and SDA are technically feasible control options for this unit.

3.1.4 Switching to Lower Sulfur Coal

Switching to a lower sulfur coal is a feasible method for lowering SO_2 emissions. In fact, Entergy has been purchasing lower sulfur coals and blending them in its feed stream for a number of years. The following graph illustrates how the Nelson Unit 6 has been able to lower its SO_2 emissions by buying lower sulfur coals for at least the last five years:

Figure 1. The Nelson Unit 6 Historic Coal Sulfur Content

[15] This is somewhat confusing since trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.



It can be seen from this figure that beginning in the Spring of 2015, Entergy began purchasing coals with lower sulfur contents that occur in a tighter range in comparison to those it has purchased in the past. This indicates that lower sulfur coal is a feasible control option.

3.2 Evaluation of Control Effectiveness of Remaining Control Technologies for Nelson Unit 6

In the following subsections we evaluate the control levels each technically feasible technology is capable of achieving for the coal and gas units. In so doing, we consider the maximum level of control each technology is capable of delivering based on a 30 Boiler Operating Day (BOD) period. As the BART Guidelines direct, "[y]ou should consider a boiler operating day to be any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit."[16] To calculate a 30 day rolling average based on boiler operating day, the average of the last 30 "boiler operating days" is used. In other words, days are skipped when the unit is down, as for maintenance. This, in effect, provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

3.2.1 Evaluation of Control Effectiveness of DSI

The efficiency of DSI system depends on many factors, such as[17]:

- Sorbent particle size: Finer particles result in better performance.

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[16] 70 FR 39103, 39172 (July 6, 2005) [40 CFR 51, App. Y]

[17] Wood, M., Kong, Y., "Dry Sorbent Injection with Trona or Sodium Bicarbonate Meets HCl Limit in Utility MACT, SOLVAir® Solutions, Solvay Chemicals, Inc.

- Sorbent residence time in flue gas stream: Longer residence time gives more time for mixing and chemical reactions, thus better performance.
- Sorbent penetration and mixing with flue gas: Better sorbent penetration into flue gas and mixing gives higher removal efficiencies.
- Particulate control device used (ESP or Baghouse): Since sorbents can build up on the fabric filters of the bag house and provide a layer of sorbent for further reactions with acid gases, baghouse filters have higher efficiencies.
- Temperature at injection site: The minimum flue gas temperature at the sorbent injection should be at least 275 ^{o}F. Higher temperatures normally result in better performance.
- The recommended maximum temperature is 1500 ^{o}F.

Solvay Chemicals, Inc., a manufacturer of DSI sorbents, provides general performance information: [18]

[18] "Dry Sorbent Injection of Sodium Sorbents," presented at the LADCO Lake Michigan Air Directors Consortium, Emission Control and Measurement Technology for Industrial Sources Workshop, March 24, 2010. We note that a number of different DSI trona SO_2 performance curves exist and our use of these curves is as a general reference only.

Figure 2. Typical Trona SO_2 Removal Rates with ESP or Baghouse Installations

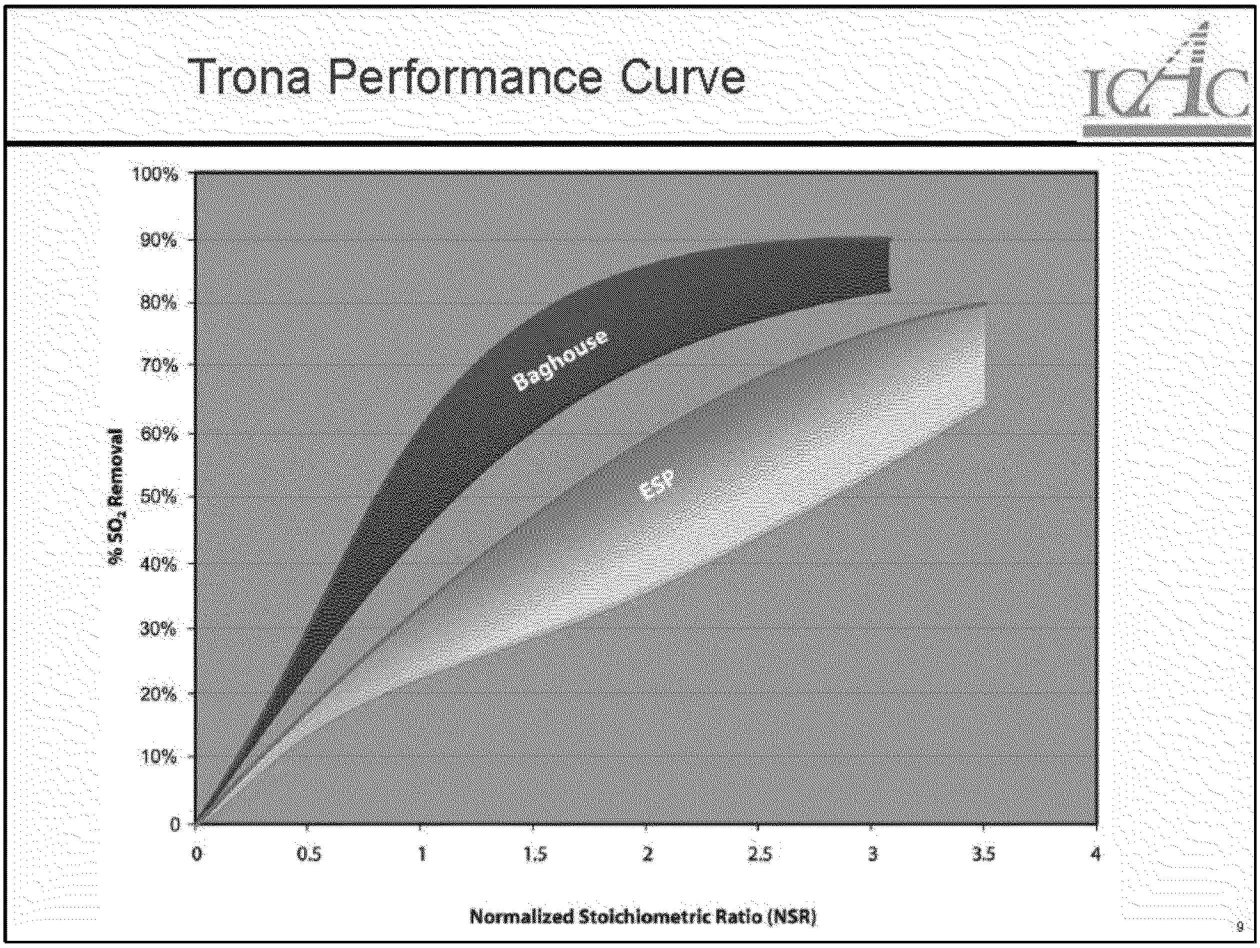

Figure 2 illustrates a number of important concepts concerning the performance potential of DSI:

- SO_2 removal efficiencies for trona DSI installations perform better when a baghouse rather than an ESP particulate control device is employed.
- The Normalized Stoichiometric Ratio (NSR), which is simply a measure of the actual usage needed compared to the theoretical need, governs the SO_2 removal efficiency. In other words, for a given particulate control device, greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.
- A wide range of SO_2 removal efficiency is possible for a given NSR and particulate control device. We interpret this range to be in part dependent on site specific conditions.

To address this range, we will use the following methodology:

- We will evaluate the Nelson Unit 6 at its maximum theoretical DSI performance level, according to the IPM DSI cost model documentation,[19] assuming milled trona: 80% SO_2 removal for an ESP installation. This level of control is within that of SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.

- However, because we do not have performance testing for Unit 6 (1) we do not know whether this unit is actually capable of achieving these control levels and (2) we believe it is useful to evaluate lesser levels of DSI control (and correspondingly lower costs). We therefore also evaluate the Nelson Unit 6 at a DSI SO_2 control level of 50%, which we believe is likely achievable.

3.2.2 Evaluation of Control Effectiveness of Wet FGD and SDA

Our wet FGD control cost analysis uses the wet FGD cost algorithms, as employed in version 5.13 of our IPM model. [20] The IPM wet FGD Documentation states: "The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu." This level of control is achievable with wet FGD.[21] We therefore have assumed a wet FGD level of control to be a maximum of 98% not to go below 0.04 lbs/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu.

Based upon industry publications and real world monitoring data, we have assumed a SDA level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06

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[19] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p. 7.

[20] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-5_dsi_cost_methodology.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-2: SDA FGD Cost Methodology, downloaded from https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-2_sda_fgd_cost_methodology_3.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-1: Wet FGD Cost Methodology, downloaded from https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-1_wet_fgd_cost_methodology.pdf.

[21] The control efficiencies reasonably achieveable by dry scrubbing and wet scrubbing are 95% and 98%, respectively. See 76 FR 81727, 81742 (December 28, 2011) and the accompanying TSD and Response to Commentsd document for that action; *Oklahoma v. EPA*, 723 F.3d 1201 (10th Cir. - 2013), cert. denied 134 S. Ct. 2662 (2014).

lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. We believe that this level of control for SDA is reasonable.

3.2.3 Evaluation of Control Effectiveness of Switching to Lower Sulfur Coal

Entergy's BART analysis states, "Switching to a lower sulfur coal can reduce SO_2 emissions to approximately 0.6 lb/MMBtu."[22]

Below we provide a summary of some of the information Entergy is required to report to the Energy Information Agency (EIA) regarding where it purchases its coal, the heat content of that coal, and its sulfur content.[23]

Table 2. Recent Entergy Nelson Coal Characteristics

Date (assume 15th day)	**Quantity (short tons)**	**Average Heat Content (Btu/lb)**	**Average Sulfur Content (weight %)**	**Calculated SO_2 (lbs/MMBtu)**	**Fuel Cost (cents/MMBtu)**
9/15/2013	14,729.0	8,810	0.18	0.409	270.5
2/15/2014	29,954.0	9,035	0.19	0.421	247.7
12/15/2014	15,214.0	8,915	0.19	0.426	247.8
11/15/2014	15,204.0	9,030	0.20	0.443	279.5
6/15/2015	15,239.0	9,025	0.20	0.443	279.5
3/15/2014	15,201.0	8,890	0.21	0.472	261.4
6/15/2013	75,780.0	8,850	0.21	0.475	267.5
7/15/2014	15,089.0	8,895	0.22	0.495	247.1
11/15/2016	15,098.0	8,635	0.22	0.510	229.5
2/15/2016	30,032.0	8,985	0.23	0.512	254.5
12/15/2016	30,465.0	8,985	0.23	0.512	229.7
4/15/2013	60,850.0	8,955	0.23	0.514	268.9
5/15/2013	60,267.0	8,950	0.23	0.514	264.7
2/15/2013	45,256.0	8,945	0.23	0.514	273.3
5/15/2015	45,633.0	8,940	0.23	0.515	252.1
11/15/2015	14,370.0	8,940	0.23	0.515	233.6
12/15/2015	90,214.0	8,940	0.23	0.515	242.0
7/15/2013	59,893.0	8,940	0.23	0.515	262.3
2/15/2012	15,141.0	8,925	0.23	0.515	244.9
1/15/2014	60,893.0	8,910	0.23	0.516	196.9

22 Entergy Nelson BART Analysis, pdf 15.
23 See the file, "Nelson control costs with Entergy Corrections.xlsx," Tab "EIA 923 Purchased Coal Data."

3/15/2013	91,081.0	8,885	0.23	0.518	265.3
11/15/2015	75,413.0	8,990	0.24	0.534	239.8
6/15/2014	15,173.0	8,590	0.23	0.536	288.0
5/15/2016	45,486.0	8,945	0.24	0.537	242.7
9/15/2016	30,298.0	8,800	0.24	0.545	253.2
1/15/2016	44,982.0	9,060	0.25	0.552	255.8
10/15/2016	15,071.0	9,010	0.25	0.555	239.1
3/15/2012	14,481.0	8,990	0.25	0.556	244.3
9/15/2015	14,883.0	8,965	0.25	0.558	240.7
11/15/2016	29,963.0	8,940	0.25	0.559	229.9
2/15/2014	29,717.0	8,895	0.25	0.562	274.4
8/15/2013	30,067.0	8,865	0.25	0.564	269.6
5/15/2012	30,372.0	8,850	0.25	0.565	274.1
12/15/2015	104,960.0	8,990	0.26	0.578	230.8
7/15/2016	45,167.0	8,980	0.26	0.579	246.2
1/15/2013	45,592.0	8,975	0.26	0.579	259.4
12/15/2016	15,096.0	8,610	0.25	0.581	229.5
1/15/2012	15,049.0	8,945	0.26	0.581	246.8
12/15/2016	45,480.0	8,910	0.26	0.584	245.3
8/15/2015	45,219.0	8,910	0.26	0.584	240.7
6/15/2016	30,286.0	9,080	0.27	0.595	241.4
6/15/2014	30,815.0	8,990	0.27	0.601	257.4
9/15/2012	60,712.0	8,990	0.27	0.601	259.3
8/15/2014	30,679.0	8,965	0.27	0.602	249.6
11/15/2016	14,230.0	8,955	0.27	0.603	249.5
11/15/2016	30,160.0	8,950	0.27	0.603	229.9
8/15/2014	30,790.0	8,925	0.27	0.605	247.7
7/15/2015	59,978.0	8,910	0.27	0.606	245.0
4/15/2016	15,242.0	8,415	0.26	0.618	243.0
11/15/2013	29,889.0	8,990	0.28	0.623	232.6
6/15/2012	45,251.0	8,980	0.28	0.624	263.1
8/15/2016	30,335.0	8,950	0.28	0.626	202.5
4/15/2015	15,196.0	8,605	0.27	0.628	262.7
7/15/2015	45,337.0	8,920	0.28	0.628	236.7
4/15/2015	45,367.0	8,910	0.28	0.629	246.9
9/15/2012	76,286.0	8,540	0.27	0.632	253.0
10/15/2012	90,992.0	8,855	0.28	0.632	262.2
9/15/2015	15,476.0	9,150	0.29	0.634	244.6
6/15/2013	60,761.0	8,490	0.27	0.636	268.8
8/15/2013	75,957.0	8,470	0.27	0.638	269.5
1/15/2016	29,786.0	8,970	0.29	0.647	253.6

3/15/2014	45,408.0	8,915	0.29	0.651	239.4
3/15/2013	15,260.0	8,605	0.28	0.651	268.0
3/15/2015	14,611.0	8,880	0.29	0.653	256.0
3/15/2015	28,779.0	8,880	0.29	0.653	242.0
1/15/2012	43,697.0	8,875	0.29	0.654	246.8
12/15/2012	45,801.0	8,560	0.28	0.654	248.8
11/15/2013	149,068.0	8,545	0.28	0.655	266.6
3/15/2016	29,577.0	8,825	0.29	0.657	204.4
1/15/2014	61,008.0	8,520	0.28	0.657	270.4
5/15/2013	75,953.0	8,480	0.28	0.660	269.0
5/15/2016	30,464.0	8,445	0.28	0.663	241.9
10/15/2014	45,893.0	8,420	0.28	0.665	274.8
4/15/2016	45,487.0	8,415	0.28	0.665	237.6
5/15/2012	30,466.0	8,380	0.28	0.668	276.0
8/15/2012	45,378.0	8,380	0.28	0.668	258.4
9/15/2014	29,553.0	8,910	0.30	0.673	248.8
8/15/2012	45,902.0	8,895	0.30	0.675	263.1
1/15/2015	105,546.0	8,880	0.30	0.676	246.6
5/15/2014	45,512.0	8,830	0.30	0.680	255.5
7/15/2012	15,204.0	8,535	0.29	0.680	255.4
8/15/2014	60,819.0	8,515	0.29	0.681	278.2
2/15/2013	30,419.0	8,495	0.29	0.683	277.3
12/15/2013	150,814.0	8,490	0.29	0.683	270.7
9/15/2013	105,527.0	8,480	0.29	0.684	272.7
6/15/2016	75,831.0	8,470	0.29	0.685	240.5
7/15/2012	75,539.0	8,465	0.29	0.685	264.0
4/15/2014	75,351.0	8,460	0.29	0.686	273.0
7/15/2014	45,700.0	8,455	0.29	0.686	281.3
9/15/2012	45,814.0	8,430	0.29	0.688	263.5
7/15/2015	30,343.0	8,425	0.29	0.688	234.4
3/15/2014	74,167.0	8,410	0.29	0.690	272.9
4/15/2013	30,297.0	8,405	0.29	0.690	276.6
2/15/2016	15,202.0	8,385	0.29	0.692	253.5
10/15/2016	45,497.0	8,380	0.29	0.692	235.8
2/15/2015	44,559.0	8,375	0.29	0.693	268.4
9/15/2014	91,198.0	8,375	0.29	0.693	280.7
8/15/2016	44,522.0	8,355	0.29	0.694	247.8
12/15/2016	60,244.0	8,355	0.29	0.694	244.8
5/15/2015	29,933.0	8,355	0.29	0.694	244.3
4/15/2014	60,204.0	8,880	0.31	0.698	244.5
2/15/2016	30,316.0	8,300	0.29	0.699	245.2

12/15/2012	106,105.0	8,870	0.31	0.699	252.1
7/15/2013	75,285.0	8,860	0.31	0.700	236.0
5/15/2014	30,481.0	8,505	0.30	0.705	279.0
4/15/2015	60,424.0	8,785	0.31	0.706	242.5
1/15/2012	42,897.0	8,500	0.30	0.706	249.1
1/15/2013	75,769.0	8,495	0.30	0.706	263.2
1/15/2013	15,233.0	8,495	0.30	0.706	265.6
3/15/2012	30,572.0	8,495	0.30	0.706	256.9
3/15/2015	45,112.0	8,490	0.30	0.707	238.0
7/15/2016	45,259.0	8,480	0.30	0.708	242.4
2/15/2014	29,618.0	8,480	0.30	0.708	281.9
12/15/2014	60,635.0	8,455	0.30	0.710	277.4
3/15/2015	44,109.0	8,450	0.30	0.710	270.0
7/15/2013	90,849.0	8,450	0.30	0.710	270.1
11/15/2012	121,611.0	8,450	0.30	0.710	256.3
8/15/2015	60,296.0	9,010	0.32	0.710	244.6
2/15/2016	45,486.0	8,445	0.30	0.710	246.3
5/15/2015	30,430.0	8,445	0.30	0.710	274.2
12/15/2012	91,373.0	8,445	0.30	0.710	242.2
1/15/2016	41,169.0	8,430	0.30	0.712	240.2
3/15/2012	60,609.0	8,425	0.30	0.712	254.0
12/15/2015	15,106.0	8,420	0.30	0.713	260.7
5/15/2016	30,307.0	8,415	0.30	0.713	237.5
1/15/2015	89,750.0	8,415	0.30	0.713	273.4
8/15/2015	15,104.0	8,415	0.30	0.713	266.6
8/15/2015	60,634.0	8,415	0.30	0.713	238.9
2/15/2012	75,592.0	8,415	0.30	0.713	253.4
2/15/2015	30,350.0	8,400	0.30	0.714	245.6
3/15/2016	15,203.0	8,395	0.30	0.715	242.0
10/15/2012	91,530.0	8,395	0.30	0.715	261.3
12/15/2016	45,027.0	8,390	0.30	0.715	238.5
3/15/2016	30,422.0	8,365	0.30	0.717	233.5
9/15/2016	60,383.0	8,350	0.30	0.719	243.5
9/15/2016	60,464.0	8,340	0.30	0.719	239.9
4/15/2015	15,102.0	8,310	0.30	0.722	248.8
11/15/2012	105,820.0	8,850	0.32	0.723	264.2
4/15/2012	15,320.0	8,805	0.32	0.727	294.1
11/15/2015	30,273.0	8,470	0.31	0.732	236.1
6/15/2016	29,570.0	8,465	0.31	0.732	235.4
1/15/2016	29,696.0	8,450	0.31	0.734	244.6
10/15/2013	45,842.0	8,435	0.31	0.735	284.7

3/15/2012	15,213.0	8,975	0.33	0.735	229.0
6/15/2012	45,654.0	8,425	0.31	0.736	258.5
8/15/2012	61,249.0	8,420	0.31	0.736	265.4
7/15/2016	90,559.0	8,415	0.31	0.737	236.7
8/15/2016	59,922.0	8,385	0.31	0.739	240.0
4/15/2012	15,108.0	8,380	0.31	0.740	296.1
2/15/2012	45,027.0	8,355	0.31	0.742	262.0
9/15/2015	15,207.0	8,335	0.31	0.744	238.9
7/15/2014	76,017.0	8,850	0.33	0.746	254.8
6/15/2012	30,069.0	8,450	0.32	0.757	264.7
1/15/2015	75,928.0	8,965	0.34	0.759	256.1
2/15/2015	59,315.0	8,950	0.34	0.760	254.4
9/15/2015	15,416.0	8,390	0.32	0.763	266.6
5/15/2013	105,572.0	8,885	0.34	0.765	238.0
10/15/2012	60,420.0	8,345	0.32	0.767	260.1
4/15/2014	75,564.0	8,835	0.34	0.770	252.0
7/15/2012	91,116.0	8,825	0.34	0.771	265.7
1/15/2012	88,552.0	8,415	0.33	0.784	258.5
9/15/2014	45,530.0	8,825	0.35	0.793	252.9
2/15/2015	45,383.0	8,735	0.35	0.801	251.9
1/15/2012	73,280.0	8,810	0.36	0.817	259.9
1/15/2014	75,070.0	8,775	0.36	0.821	243.5
4/15/2013	45,483.0	8,885	0.37	0.833	240.7
3/15/2014	76,000.0	8,875	0.37	0.834	245.6
8/15/2013	90,517.0	8,825	0.37	0.839	238.4
1/15/2013	45,504.0	8,770	0.37	0.844	239.3
12/15/2013	60,076.0	8,760	0.38	0.868	238.0
6/15/2013	59,717.0	8,750	0.38	0.869	240.2
2/15/2012	60,153.0	8,890	0.39	0.877	259.1
12/15/2014	30,380.0	8,995	0.40	0.889	246.2
10/15/2014	15,220.0	9,020	0.41	0.909	244.0
9/15/2013	15,186.0	8,695	0.41	0.943	240.1
1/15/2014	45,140.0	8,810	0.42	0.953	243.4
11/15/2013	30,170.0	8,755	0.42	0.959	237.4
3/15/2012	30,381.0	8,755	0.43	0.982	264.6
5/15/2014	14,851.0	8,765	0.44	1.004	250.4
10/15/2014	30,238.0	8,700	0.46	1.057	252.1

In Table 2 above, we have ordered the data based on increasing sulfur content. This information indicates that Entergy has been able to consistently purchase coal with a sulfur content that would enable the Nelson Unit 6 to comply with the 0.60 lbs/MMBtu level Entergy has selected for its low sulfur coal BART case. Note that the color coding of the 2016 coal purchases is utilized in Section 3.2.9, where we discuss our calculations of the cost-effectiveness of switching to a lower sulfur coal.

3.2.4 Entergy's Cost Analysis:

The Entergy Nelson BART analysis is contained in a report by Trinity Consultants, which incorporates control cost analyses prepared by Sargent & Lundy (S&L). This report was revised April 15, 2016, in response to comments made by us on March 16, 2016. Entergy made some adjustments in response to our comments. However, it did not remove certain cost items that are not allowed by the Control Cost Manual. For instance, although Entergy deleted Allowance for Funds Used During Construction (AFUDC), it did not remove escalation during construction, and owner's costs. These costs are not allowed by the Control Cost Manual. We also believe Entergy's use of a 25% contingency factor is not supported We are not aware of any characteristics of Nelson Unit 6 would present any unusual difficulty that would serve to distinguish it from any other scrubber retrofit and thus justify a high estimate for contingency. The Control Cost Manual uses contingency values ranging from 5 to 15%, depending upon the control device in question and the precise nature of the factors requiring contingency.[24] ,Below is a summary of Entergy's SDA control cost-effectiveness in order to illustrate the effect of those disallowed costs and our contingency adjustment.[25] We have used a contingency value of 10% for this estimate, which lies in the middle of the range employed in the Control Cost Manual, which we believe is appropriate for mature technologies such as SDA and wet FGD.

Table 3. Impact of Disallowed Costs on Entergy's SDA Control Cost Calculation

Entergy SDA Cost Calculation	
TCI	$394,845,800
Annualized capital costs	$31,819,203
Variable O&M	$10,168,000
Fixed O&M	$5,700,000
Total Annual Cost	$47,687,203
$/ton	**$5,094***

Entergy's SDA Cost Calculation with Deletion of Escalation and Owner's Costs	
TCI	$394,845,800
Subtract escalation	($39,743,100)
Subtract escalation addition	($4,358,800)

[24] "A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. For example, a hundred year flood may postpone delivery of materials, but their arrival at the job site is not a problem unique to a retrofit situation." Control Cost Manual, 6th Edition, Section 2.5.4.2.

[25] See the file, "Nelson control costs with Entergy Corrections.xlsx" for details of these and our other control cost calculations.

Subtract Owner's costs	($20,185,200)
Adjusted TCI	$330,558,700
Annualized capital costs	$26,638,537
Variable O&M	$10,168,000
Fixed O&M	$5,700,000
Total Annual Cost	$42,506,537
$/ton	**$4,541***

Entergy's SDA Cost Calculation with Deletion of Escalation and Owner's Costs and Reducing Contingency to 10%	
TCI	$394,845,800
Subtract escalation	($39,743,100)
Subtract escalation addition	($4,358,800)
Subtract Owner's costs	($20,185,200)
Subtract original 25% contingency	($70,148,800)
Add 10% contingency	25,231,490
Adjusted TCI	$285,641,390
Annualized capital costs	$23,018,812
Variable O&M	$10,168,000
Fixed O&M	$5,700,000
Total Annual Cost	$38,886,812
$/ton	**$4,154***

* Note these figures are obtained by dividing Entergy's total annual cost by a SO_2 reduction of 9,361 tpy, which represents a reduction of 92.11% to a floor of 0.06 lbs/MMBtu, from a baseline of 10,1163 tpy. This baseline, which differs slightly from Entergy's value, is used here to enable an apples-to-apples comparison with our cost analyses which we present elsewhere in this TAD.

As can be seen from the above tables, removing the costs not allowed in the Control Cost Manual and adjusting contingency to 10% has a significant impact.

In addition to the above issues, Entergy's cost analysis is based on a proprietary database. Therefore, the cost estimates cannot be independently verified.

3.2.5 Our Control Cost Analyses for the Nelson Unit 6

In consideration of the issues we have outlined above, we have conducted our own cost analyses for the Nelson Unit 6.

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[26]

After you identify the available and technically feasible control technology options, you are expected to conduct the following analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance,
Impact analysis part 2: Energy impacts, and
Impact analysis part 3: Non-air quality environmental impacts.
Impact analysis part 4: Remaining useful life.

In developing our cost estimates for the Nelson Unit 6, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[27] The Control Cost Manual uses the "overnight" method of cost estimation: [28]

The Control Cost Manual uses the overnight method of cost estimation, widely used in the utility industry. The U.S. Energy Information Administration (EIA) defines ''overnight cost'' as ''an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs.'' The overnight cost is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. The overnight method is appropriate for BART determinations because it allows different pollution control equipment to be compared in a meaningful manner. Because ''different controls have different expected useful lives and will result in different cash flows, the first step in comparing alternatives is to normalize their returns using the principle of the time value of money. The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value analysis. In either case, the calculation is the same: Adjust the value of future money to values based on the same point in time (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together.''

We proceed in our SO_2 costing analyses by examining the current SO_2 emissions and the level of SO_2 control, if any, for the Nelson Unit 6. Noting that this unit has no post-combustion SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber.

In order to estimate the costs for DSI, SDA scrubbers, and wet FGD scrubbers, we programmed the DSI, SDA and wet FGD cost algorithms, as employed in version 5.13 of our IPM model, referenced above, into three spreadsheets. These cost algorithms calculate the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. We verified these spreadsheets by reproducing the costs

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[26] 70 FR 39103, 39166 (July 6, 2005) [40 CFR Part 51, App. Y].
[27] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002 available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf.
[28] 76 FR 81727, 81744 (December 28, 2011).

estimated by Sargent & Lundy in the project reports. We further extended these cost algorithms to calculate the annualized costs per ton of SO_2 removed ($/ton). We then performed DSI, SDA and wet FGD cost calculations for the Nelson Unit 6.[29] We discuss the inputs and outputs for the DSI, SDA, and wet FGD cost models below. These cost models were based on costs escalated to 2012 dollars.[30] Because the IPM 5-13 cost algorithms were calculated in 2012 dollars, we have escalated them to 2016, using the annual Chemical Engineering Plant Cost Indices (CEPCI). We present the results of our DSI, SDA, and wet FGD cost analyses in sections 3.2.6, 3.2.7, and 3.2.8.

3.2.6 Impact Analysis Part 1: Cost of Compliance for DSI

Table 4, below, is a depiction of the input section of the DSI cost spreadsheet. Sample input parameters for the DSI cost calculation are represented by yellow highlighted cells. The input values designated "A" through "U" have the same meaning as those contained within the documentation for the IPM DSI cost algorithms (hereafter referred to as the "IPM DSI documentation") referenced above. The last four input values, (i.e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

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[29] These calculations are present in the spreadsheet, "Nelson Control Costs with Entergy Corrections.xlsx," and are located in our Docket.

[30] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

Table 4. Sample Input DSI Cost Model

Variable	Designation	Units	Value	Calculation	
Unit Size (Gross)	A	(MW)	**500**	**<---- User Input**	
Retrofit Factor	B		**1**	**<---- User Input (An "average" retrofit has a factor = 1.0)**	
Gross Heat Rate	C	(Btu/kWh)	**9,500**	**<---- User Input**	Max annual value from 2011-2015
SO2 Rate	D	(lb/MMBtu)	**2.00**	**<---- User Input**	Max monthly value from 2011-2015
Type of Coal	E		**Bituminous**	**<---- User Input (PRB, BIT, LIG, or LIG-PRB Blend)**	
HHV Bituminous		BTU/lb	**11,000**	**<---- User Input (default is 11,000 Btu/lb if applicable; else no meaning)**	
HHV PRB		BTU/lb	**8,400**	**<---- User Input (default is 8,400 Btu/lb if applicable; else no meaning)**	Three year average from 2011-2015, excluding max and min values
HHV Lignite		BTU/lb	**7,200**	**<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)**	
Percent Lignite if Blended			**50**	**<---- User Input (If Type of Coal = "LIG-PRB Blend," Enter % Lignite. Remainder assumed PRB. If not "LIG-PRB Blend," no meaning)**	
Particulate Capture	F		**ESP**	**<---- User Input**	
Milled Trona	G		**TRUE**	**<---- User Input**	
Removal Target	H	%	**50**	**Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90%**	One run with 50%, and another with either 80% or 90% based on particulate control device used
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000	
NSR	K		1.43	Unmilled Trona with an ESP = If(H<40,0.0350*H,0.352e ^(0.0345*H)) Milled Trona with an ESP = If(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = If(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = If(H<40,0.0160*H,0.208e^(0.0281*H))	Pg 3 of the documentation lists example calculated NSRs which differ from those calculated from the formulae here. Per emails from Bill Stevens, the documentation is in error.
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011*10^-6)*K*A*C*D	
Sorbent Waste Rate	N	(ton/hr)	11.65	(0.7387-0.00073696*H/K)*M; Based on a final reaction product of NA2SO4 and unreacted drysorbent as NA2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.	
Include Fly Ash Waste Rate in VOM	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV= 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV= 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2 HHV= 7200 For Blend Coal: Ash is proportional to lignite and PRB; Boiler Ash Removal = 0.2; HHV is proportional to lignite and PRB	Assume fly ash waste rate is included in VOM
Include Aux Power in VOM	Q	(%)	0.65	If Milled Trona M*20/A, else M*18/A	Assume aux power is included in VOM
Trona Cost	R	($/ton)	**170**	**<---- User Input**	default value
Waste Disposal Cost	S	($/ton)	**50**	**<---- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)**	default value
Aux Power Cost	T	($/kWh)	**0.06**	**<---- User Input**	default value
Operating Labor Rate	U	($/hr)	**60**	**<---- User Input (Labor cost including all benefits)**	default value
Interest Rate		(%)	**7**	**<---- User Input**	
Equipment Lifetime		(years)	**30**	**<---- User Input**	
Gross Load		(MW-hours)	**4,000,000**	**<---- User Input**	3 -yr avg. 2011-2015, excluding max and min
SO2 Emission Baseline		(tons/year)	**30,000**	**<---- User Input**	3 -yr avg. 2011-2015, excluding max and min

3.2.6.1 Selection of DSI Cost Model Input Parameters

Below, we review the DSI Cost Model input values and discuss the procedures we employed in selecting them when constructing the costs for the DSI installation. For selected input parameters, we also discuss uncertainties in their values and how we dealt with them. Our overall goal was to select input parameters that would result in a cost that would be a reasonably conservative value. We took this approach in order to ensure that the DSI system was designed to address any operating conditions the unit had experienced in the last five years.

<u>Unit Size (Gross).</u> This parameter is simply the unit size expressed in Megawatts (MW). Although our intent was to use gross and not net values, we are aware that MW values are often reported incorrectly, inconsistently, or the reported values are not specified as to whether they are gross or net values.

Retrofit Factor. The retrofit factor represents a subjective estimation of the average retrofit difficulty. Because we are not aware of any significant retrofit issues at any of the facilities we evaluated, we adopted the default retrofit value of 1.0, which represents an average retrofit difficulty, for all the units we evaluated.

Gross Heat Rate. We calculated the gross heat rate by dividing the Heat Input (MMBtu) by the Gross Load (MW-h), downloaded from our Air Markets Program Data website,[31] and multiplying the result by 1000W/kW to get (BTU/kWh). We chose the gross heat rate to be the maximum annual gross heat rate (Btu/kWh) value from 2011 – 2015 for each unit.

SO_2 Rate. The SO_2 emission rate was calculated from monthly emission data.[32] It was selected as the maximum monthly value from 2011 – 2015. As per the IPM DSI documentation, the SO_2 emission rate has a built-in upper limit of 2.0 lbs/MMBtu.

Type of Coal. The cost algorithms allows the input of three types of coal: bituminous, lignite, and Powder River Basin (PRB) coal from Wyoming. Within the DSI cost algorithms, the type of coal is an input to an interim calculation (P), which is partly dependent on High Heat Value (HHV) of the coal. Also, the cost algorithms assume default values for the HHV of 11,000 Btu/lb for bituminous coal, 8,400 Btu/lb for PRB, and 7,200 Btu/lb for lignite. The interim calculation, P, itself is an input to the variable O&M cost for waste disposal (VOMW).

We note that the cost algorithms are somewhat sensitive to the selection of the type of coal. In addition, we wished to allow for the input of more accurate HHV coal values. Therefore, we adjusted the cost algorithms by (1) adding an option for a lignite-PRB coal blend, which if selected requires (2) the input of the percentage of lignite burned (remaining percentage is assumed to be PRB), plus (3) inputs for the HHV of the coals being burned. Our adjusted cost model accounts for this information in the calculation of the VOMW.

Particulate Capture. The cost model allows for the input of either an Electrostatic Precipitator (ESP) or a Baghouse (BGH) as the particulate control device. As the IPM DSI documentation states, "Baghouses generally achieve greater SO_2 removal efficiencies than ESPs by virtue of the filter cake on the bags, which allows for longer reaction time between the sorbent solids and the flue gas."[33] We assumed the existing particulate control device has the capacity to handle the additional load due to the addition of the trona. Entergy has verbally indicated that may not be the case but we have not been able to confirm.

Milled Trona. As discussed in the IPM DSI documentation, trona is the most commonly used sodium based sorbent material for DSI installations and the DSI cost algorithms assume trona. For a given mass, increasing the surface area of the trona has the effect of improving its ability to

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[31] http://ampd.epa.gov/ampd/

[32] Ibid.

[33] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p.1.

remove SO_2 from the flue gas. One common method for increasing the surface area is to mill the trona to a particle size of 30 μm or smaller, using in-line mills. This usually results in slightly higher capital costs, but the overall cost effectiveness of milling the trona improves (lower $/ton), due to the reduction in trona required to achieve a given SO_2 removal target. We assumed that trona would be milled.

We note, however, that other reagents have important advantages over the use of trona. Hydrated lime, for example, is less sensitive to the conditions of the pneumatic transport air, so less dehumidification or cooling is required for handling; the waste generated by lime injection is not soluble, so normal landfill disposal is feasible without encapsulation, lowering disposal costs; milling is not required; and hydrated lime is usually cheaper.

Removal Target. The removal target is the percentage reduction in SO_2 desired from the SO_2 rate discussed above. The IPM DSI documentation states, "When the sorbent is captured in an ESP, a 40 to 50% SO_2 removal is typically achieved without an increase in particulate emissions. A higher efficiency (70 – 75%) is generally achieved with a baghouse."[34] In section 3.2.1, we reproduce general DSI performance information from Solvay Chemicals, Inc., a manufacturer of DSI sorbents and we discuss our rational for selecting our proposed level of control.

Include Fly Ash Waste Rate in VOM. The cost model allows for the inclusion or exclusion of the fly ash in the Variable O&M costs for waste disposal via a drop down menu. As the IPM DSI documentation notes, when the sodium sorbent (e.g., trona) is captured in the same particulate control device as the fly ash, the resulting waste must be land filled. We are aware that a number of facilities sell their fly ash, and that the addition of trona may render that fly ash unsalable. We chose this option in all cases.

We note that a few of the units we analyzed use an ESP with a polishing baghouse. Such a configuration could allow for the injection of the trona between the ESP and the baghouse, thus allowing for excluding the fly ash from the VOM calculation. This would have the effect of significantly improving the cost effectiveness (reducing the $/ton). However, as the IPM DSI documentation notes, the disposal cost (discussed below) should be increased to account for the additional difficulty in handling the pure sodium waste product. This has the effect of diminishing the cost effectiveness (increasing the $/ton), and erasing much of the gain from excluding the fly ash waste rate from the VOM.

Include Aux Power in VOM. The cost model allows for the inclusion or exclusion of the additional auxiliary power required for the DSI system to be included in the variable operating costs via a drop down menu. We chose to include this additional auxiliary power.

Trona Cost. The cost of trona is the largest portion of the variable operating costs. It is partly dependent on the delivery costs. We used the value obtained from 4/15/16 Trinity Nelson BART analysis.

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[34] Ibid., p.2.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model suggests a cost of \$50/ton if the trona waste and fly ash are comingled and disposed of together, and \$100/ton, if the trona waste is not comingled with the fly ash and is disposed of separately. The value used in the 4/15/16 Trinity Nelson BART analysis is \$7.50/ton, which is very low in comparison to typical values we have seen. We assumed a value of \$50/ton, corresponding to the trona waste and fly ash being comingled, which we use pending documentation from Entergy. We note that the waste disposal cost is an area in which our cost model could be under predicting the true cost. Because adding trona to the fly ash increases the water solubility of the waste, an upgraded landfill may be required.[35]

Aux Power Cost. Auxiliary power cost is the additional power required by the DSI control system. It is the smallest portion of the variable operating costs. We note from our examination of CBI material we received in response to our Section 114(a) requests that the true power cost for most if not all of the units we analyze is considerably less than this value. However, the cost model is fairly insensitive to the value used for the auxiliary power cost, and we assumed the default value of \$0.06/kWh in all cases.

Operating Labor Rate. The operating labor rate is the largest portion of the fixed operating and maintenance cost. We chose the default value of \$60/hour for all cases.

Interest Rate. The interest rate is used in the calculation of the capital recovery factor, which itself is used in the calculation of the annualized capital costs. This input value is not a part of the IPM DSI cost algorithms and was added by us in order to calculate the cost effectiveness in \$/ton. For cost analyses related to government regulations, an appropriate "social" interest (discount) rate should be used, unless site specific informaton is available. We calculated capital recoveries using 3 percent and 7 percent interest rates in determining cost -effectiveness for the Regulatory Impact Analysis (RIA) for the BART Guidelines.[36] Also, a 7 percent interest rate is recommended by Office of Management and Budget.[37]

Equipment Lifetime. The equipment lifetime is another factor used in the in the calculation of the capital recovery factor. This input value is not a part of the IPM DSI cost algorithms and was added by us in order to calculate the cost effectiveness in \$/ton. It represents the actual or service life of the equipment in question. Because a DSI system is relatively simple and reliable, we have no reason to conclude that its service life would be any less than what we typically use for scrubber cost analyses. We therefore adopt that same value here, which is 30 years.

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[35] The Ins and Outs of SO_2 Control, Lindsay Morris, Power Engineering, 6-1-2012. "Jonas Klingspor, vice president of business development and marketing for URS, said one potential concern for using DSI systems with trona is the disposal of the product. 'Unless you have a double-lined, capped landfill, the water soluble byproduct may be a serious concern.'"

[36] Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, EPA-0452/R-05-004 (June 2005).

[37] A 7.0 percent interest rate is recommended by Office of Management and Budget, Circular A-4, Regulatory Analysis, https://www.whitehouse.gov/omb/circulars_a004_a-4

Gross Load. The gross load (MW-h) was obtained from emissions data downloaded from our Air Markets Program Data website.[38] It was selected as the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. We concluded that using this kind of an average was a reasonable compromise between simply selecting the maximum value from 2011 – 2015, or using the average of the values from 2011 – 2015. This input value is not a part of the IPM DSI cost algorithms. It was added by us in order to convert the variable and operating costs, which the cost algorithms express in \$/MW-h and \$/kW-yr, respectively, into dollars which are subsequently used in calculating the cost effectiveness in dollars per ton of SO_2 removed (\$/ton).

SO_2 Emission Baseline. The SO_2 emission baseline is calculated from emissions data downloaded from our Air Markets Program Data website.[39] It was selected as the 20011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. This input value is not a part of the IPM DSI cost algorithms. It was added by us in order to calculate the annual SO_2 emission reduction from the installation of DSI, which itself is an input to the cost effectiveness in \$/ton. We concluded that using this kind of an average was a reasonable compromise between simply selecting the maximum value from 2011 – 2015, or using the average of the values from 2011 – 2015.

In addition to the above inputs to our DSI cost model, we note that Entergy states that the addition of DSI would result in the loss of revenue from fly ash sales. Entergy reports that the loss of fly ash sales due to the installation of DSI will cost it \$621,000 per year, and adds this value to its operating and maintenance costs.[40] It states that this assumes 100% of the station's fly ash was being sold on an annual basis for an average of approximately \$8.00 per ton. In this case, it appears that at least as recently as October, 2016, Nelson Unit 6 was disposing of some fly ash in an onsite disposal landfill.[41] Consequently, we did not include this cost.

Loss of Fly Ash Sales: Note that our DSI cost analysis does not include the loss in fly ash sales that Entergy states it would incur as a result of contamination of DSI sorbent rendering the fly ash unsalable.[42] Entergy estimates this cost as \$8/ton of fly ash generated for a total of \$621,000 a year added to the variable O&M cost. However, this estimate was based on assuming 100% of fly ash sales, and in its 4/15/16 letter, Entergy clarified that although historically approximately

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[38] http://ampd.epa.gov/ampd/

[39] Ibid.

[40] See page 11of the S&L Nelson Unit 6 Dsi Cost Estimate Basis Document, November 6, 2015, attached to the 4/15/16 Trinity Nelson BART analysis.

[41] See the Coal Combustion Residuals (CCR) Landfill Post-Closure Plan, Entergy Louisiana LLC - Nelson Coal Ash Disposal Landfill Westlake, Louisiana October 17, 2016, available here: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&cad=rja&uact=8&ved=0ahUKEwjrpKTkuc7RAhVK4yYKHSjfAGYQFggfMAE&url=http%3A%2F%2Fwww.entergy-louisiana.com%2Fcontent%2Fccr%2Fdocs%2FNelsonCADLCCRPOSTCLOSUREPLANStampled10-13-16.pdf&usg=AFQjCNEFgGBDcUFVQ5B0t7cc5qChXWDNeg&bvm=bv.144224172,d.eWE. This CCR (fly ash) landfill post-closure plan is required by 40 CFR §257.104 for post closure of a CCR landfill.

[42] See Entergy's response to our questions in its 4/15/16 letter to Guy Donaldson from Kelly McQueen, in our docket.

74% of fly ash had been sold, it received between $15 - $20/ton in compensation, concluding its estimate was conservative. Because we have not received any further documentation of these figures, we have not included the loss of fly ash sales in our DSI cost estimate. We note that adding the revenue from the loss of fly ash sales will result in worsening (higher $/ton) the cost-effectiveness of DSI.

3.2.6.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted below in Table 5. The cost algorithms calculate the Capital, Engineering and Construction Cost (CECC) and the fixed and variable operating costs (FOM and VOM, respectively). Following this, we add a calculation for the capital recovery factor, based on the interest rate and the equipment lifetime, and use it to annualize the CECC. In so doing, we exclude any Allowance for Funds Used During Construction (AFUDC) and "owner's costs."[43] To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[43] We exclude any AFUDC and "owner's costs" from regional haze control cost calculations, as they are disallowed by the "overnight" cost method used in the Control Cost Manual. In this case, however, AFUDC is assumed by the cost algorithms to be zero anyway, since a DSI project is expected to be completed within one year.

Table 5. Sample DSI Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: equipment, installation, buildings, foundations, electrical, and retrofit difficulty.	
BM ($)	$18,348,000	Base DSI module includes all equipment from unloading to injection.	
BM ($/kW)	37	Base module cost per kW	
Total Project Cost			
A1	$917,000	Engineering and construction management costs	
A2	$917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc..	
A3	$917,000	Contractor profit and fees	
CECC($)	**$21,099,000**	Capital, engineering and construction cost subtotal	excludes owner's costs
CECC($/kW)	**42**	Capital, engineering and construction cost subtotal per kW	excludes owner's costs
B1	$1,055,000	Owners costs including "home office" costs (owner engineering, management, and procurement activities)	
TPC ($)	**$22,154,000**	Total project cost without AFUDC	includes owner's costs
TPC ($/kw)	**44**	Total project cost per kW without AFUDC	includes owner's costs
B2	$0	AFUDC (zero for less than 1 year engineering and construction cycles)	
TPC ($)	**$22,154,000**	Total project cost	includes owner's costs and AFUDC
TPC ($/kw)	**44**	Total project cost per kW	includes owner's costs and AFUDC
Fixed O&M Cost			
FOMO ($/kW yr)	0.50	Fixed O&M additional operating labor costs. Based on two additional operators.	
FOMM ($/kW yr)	0.37	Fixed O&M maintenance material and labor costs	
FOMA ($/kW yr)	0.02	Fixed O&M additional addministrative labor costs	
FOM ($/kW yr)	**0.89**	Total Fixed O&M costs	
Variable O&M			
VOMR ($/MWh)	5.55	Variable O&M costs for trona reagent	
VOMW ($/MWh)	3.24	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent	
VOMP ($/MWh)	0.39	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)	
VOM ($/MWh)	**9.18**	Total variable O&M costs	
Annualization			
Capital, engineering and construction cost	$21,099,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$1,700,293		
Variable operating costs	$36,731,218	VOM*(Gross Load)	
Fixed operating costs	$404,356	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$38,835,867**		
SO2 emissions reduction (tons)	15,000	H/(100%)*(SO2 emission baseline)	
$/ton	**2,589**		

3.2.6.3 Summary of DSI Cost Model Results

Below in Table 6 is a summary of our DSI cost model results:

Table 6. Summary of DSI Cost Model Results for the Nelson Unit 6

DSI Control (%)	50	80
DSI SO_2 Reduction (tpy)	5,082	8,130
DSI Capital Cost	$17,840,000	$22,646,000
DSI Annualized Capital Cost	$1,437,661	$1,824,960
DSI Variable Operating Cost	$17,442,629	$34,672,607
DSI Fixed Operating Cost	$207,608	$229,492
DSI Total Annualized Cost	$19,087,899	$36,727,059
DSI Cost Effectiveness 2012 ($/ton)	$3,756	$4,517
DSI Cost Effectiveness 2016 ($/ton)	$3,578	$4,302

Some observations are apparent from the DSI cost model results displayed above:

- The vast majority of the total annualized cost of DSI is due to the variable operating cost, VOM. This is due to the relatively low capital cost of the equipment, and the relatively high cost of the trona.
- Unlike the cost effectiveness of scrubbers, which we will discuss below, for a given facility, the cost effectiveness of DSI worsens (higher $/ton) with increasing control levels. This is due to the inefficient use of the sorbent in DSI systems. Unlike scrubbers, in which the reaction of the reagent and the SO_2 in the exhaust gas occurs within a large vessel (e.g., an absorber), which can be highly controlled, DSI lacks an absorber. Greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.

3.2.7 Impact Analysis Part 1: Cost of Compliance for SDA

Table 7, below, is a depiction of the input section of the SDA cost spreadsheet. Sample input parameters for the SDA cost calculation are represented by the yellow highlighted cells. The input values designated "A" through "T" have the same meaning as those contained within the documentation for the IPM SDA cost algorithms (hereafter referred to as the "IPM SDA documentation") referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 7. Sample Input SDA Cost Model

Variable	Designation	Units	Value	Calculation	
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)	
Retrofit Factor	B		1	<--- User Input (an "average" retrofit has a factor =1.0)	
Gross Heat Rate	C	(Btu/kWh)	9,800	<--- User Input	Max annual value from 2011-2015
SO2 Rate	D	(lb/MMBtu)	2.00	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)	Avg. of months with full operating time
Type of Coal	E		PRB	<--- User Input (PRB, BIT, or LIG)	
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07	
Heat Rate Factor	G		0.98	C/10000	
Heat Input	H	(Btu/Hr)	4,900,000,000	A*C*1000	
Operating SO_2 Removal	J	(%)	95.00	<--- User Input (Used to adjust actual operating costs)	Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
Lime Rate	K	(Ton/Hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)	
Waste Rate	L	(Ton/Hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)	
Include Aux Power in VOM	M	(%)	1.35	(0.000547*D^2+0.00649*D+1.3)*F*G	Assume aux power is included in VOM
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000	
Lime Cost	P	($/Ton)	125	<--- User Input	Default - appears reasonable - see USGS lime report
Waste Disposal Cost	Q	($/Ton)	30	<--- User Input	default value
Aux Power Cost	R	($/kWh)	0.06	<--- User Input	default value
Makeup Water Cost	S	($/1000[gal])	1	<--- User Input	default value
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)	default value
Elevation adjustment if > 500 Feet		(feet)	0	<--- User Input (no entry needed if less than 500 feet)	Default value - check elevation.
Interest Rate		(%)	7	<---- User Input	
Equipment Lifetime		(years)	30	<---- User Input	
Gross Load		(MW-hours)	4,295,229	<---- User Input	5 -yr avg. excluding max and min
SO2 Emission Baseline		(tons/year)	30,591	<---- User Input	5 -yr avg. excluding max and min

3.2.7.1 Selection of SDA Cost Model Input Parameters

Below, for those input values that are different than our DSI cost model, we review the SDA cost model input values and discuss the procedures we employed in selecting them when developing the cost estimates for the individual SDA installations.

Type of Coal: Unlike the DSI cost algorithms discussed above, the SDA cost algorithms are relatively insensitive to the type of coal.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM SDA Documentation states: "The curve fit was set to represent proprietary in-house cost data of a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of SDA FGD systems, are 0.06 lb/MMBtu." As we discuss in Section 3.2.2, we have assumed a level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu.

Lime Cost. The cost of lime is the largest portion of the variable operating costs. At most dry scrubber facilities, the lime reagent is produced by onsite slaking of quicklime (calcium oxide) to produce a slurry of solid hydrated lime (calcium hydroxide) particles.[44] Therefore, we assume in our cost model that quicklime is delivered to the facility where it is then slaked onsite, and that this cost is a part of the "base reagent preparation and waste recycle/handling" cost module.[45] The USGS estimates the average 2012 cost of quicklime to be $116/ton at the lime plant.[46] The cost algorithm default value is $125/ton. We have employed a value of $130/ton based on the 4/15/16 Trinity Nelson BART analysis, which is included in the 2017 Louisiana Regional Haze SIP as Appendix x.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. As with its DSI cost estimate, the value used in the 4/15/16 Trinity Nelson BART analysis is $7.50/ton, which is low in comparison to typical values we have seen. We are assuming the default value is $30/ton. This has the effect of significantly worsening (increased $/ton) the cost effectiveness.

Elevation Adjustment. The IPM SDA documentation states that the cost methodology is based on a unit located within 500 feet of sea level:[47]

> The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure between sea level and the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:
>
> 14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs.

Although the cost algorithms call for this correction, no implementation was provided by S&L. Consequently, we included this atmospheric pressure adjustment in our SDA cost model by incorporating an atmospheric pressure change with elevation calculation provided by NASA.[48] In the case of the Nelson Unit 6, which is considerably below the 500 foot threshold value, this adjustment does not apply.

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44 Primex Process Specialists. "Optimizing Scrubber Performance," p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

45 IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

46 U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2013, p. 92. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2013/mcs2013.pdf

47 IPM SDA documentation, p. 2.

48 http://exploration.grc.nasa.gov/education/rocket/atmosmet.html. It should be noted that in addition to the NASA algorithm, this calculation requires converting the input feet to meters (multiplying elevation*0.3048) and K-Pa to psi (multiplying the calculation by 0.145038).

Equipment Lifetime. Similar to what we describe above in our DSI input analysis, this input value is not a part of the IPM SDA cost algorithms and was added by us in order to calculate the cost effectiveness in $/ton. It represents the actual or service life of the equipment in question. In past EPA rulemakings, we have note that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might be over 60 years.[49] We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Consequently, we used a 30 year equipment life for scrubber retrofits and upgrades.

3.2.7.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is depicted below in Table 8. As with our DSI cost model, the cost algorithms calculate the CECC and the FOM and VOM, and we add a calculation for the capital recovery factor, based on the interest rate and the equipment lifetime, and use it to annualize the CECC. We exclude AFUDC and "owner's costs." To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[49] Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190, 12/13/2011. See discussion beginning on page 36.

Table 8. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	
BMR($)	51,886,000	Base module absorber island cost	
BMF($)	31,337,000	Base module reagent preparation and waste recycle/handling cost	
BMB($)	73,422,000	Base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)	
BMBA($)	73,422,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**156,645,000**	Total Base module cost including retrofit factor	Page 6 of the S&L report gives BM=BMR+BMF+BMW+BMB. BMW appears to be an error (holdover from wet scrubber algorithm), as no formula is given for BMW.
BM($/kW)	313	Base module cost per kW	
Total Project Cost			
A1	15,665,000	Engineering and Construction Mnagement costs	
A2	15,665,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	15,665,000	Contractor profit and fees.	
CECC ($)	**203,640,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**407**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	10,182,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**213,822,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**428**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	21,382,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**235,204,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**470**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			
FOMO ($/kW-yr)	2.00	Fixed O&M additional operating labor costs. Based on eight additional operators.	
FOMM ($/kW-yr)	4.70	Fixed O&M costs for waste disposal	
FOMA ($/kW-yr)	0.12	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**6.81**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	1.81	Variable O&M costs for lime reagent	
VOMW ($/MWh)	0.96	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.81	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)	In the calculation, the factor of "10" results from dividing the conversion from kilo to mega (1000) by 100% , since the input for M is a percentage.
VOMM ($/MWh)	0.06	Variable O&M costs for makeup water	
VOM ($/MWh)	**3.64**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$203,640,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$16,410,615		
Variable operating costs	$15,645,084	VOM*(Gross Load)	
Fixed operating costs	$3,340,299	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$35,395,997**		
SO2 emissions reduction (tons)	29,061	J/(100%)*(SO2 emission baseline)	
$/ton	**1,218**		

3.2.7.3 Summary of SDA Cost Model Results

Below in Table 9 is a summary of our SDA cost model results:

Table 9. Summary of SDA Cost Model Results for Nelson Unit 6

SDA Control (%)	92.11
SDA SO_2 Reduction (tpy)	9,361
SDA Capital Cost	$243,310,000
SDA Annualized Capital Cost	$19,607,478
SDA Variable Operating Cost	$5,014,430
SDA Fixed Operating Cost	$1,975,645
SDA Total Annualized Cost	$26,597,552
SDA Cost Effectiveness 2012 ($/ton)	$2,841
SDA Cost Effectiveness 2016 ($/ton)	$2,706

In contrast to our DSI cost model results, a greater portion of the total annualized cost of SDA is due to the annualized capital costs and the annualized capital cost is greater than the total operating cost in most cases. However, the annualized capital costs and the operating costs are much closer in magnitude.

3.2.8 Impact Analysis Part 1: Cost of Compliance for Wet FGD

Table 10, below, is a depiction of the input section of the wet FGD cost spreadsheet. Sample input parameters for the wet FGD cost calculation are represented by the yellow highlighted cells. The input values designated "A" through "T" have the same meaning as those contained within the documentation for the IPM wet FGD cost algorithms (hereafter referred to as the "IPM wet FGD documentation") referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 10. Sample Wet FGD Input Parameters

Variable	Designation	Units	Value	Calculation	
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)	S&L has a drop down menu for selection of an additional WWTP facility, but no capital or operational cost are implemented so it is not reproduced here.
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor =1.0)	
Gross Heat Rate	C	(Btu/kWh)	9,500	<--- User Input	Max annual value from 2011-2015
SO2 Rate	D	(lb/MMBtu)	3.00		Avg. of months with full operating time
Type of Coal	E		BIT	<--- User Input (PRB, BIT, or LIG)	If blending, run once for PRB and one for LIG
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07	
Heat Rate Factor	G		0.95	C/10000	
Heat Input	H	(Btu/Hr)	4,750,000,000	A*C*1000	
Operating SO_2 Removal	J	(%)	95.00	<--- User Input (Used to adjust actual operating costs)	
Design Limestone Rate	K	(Ton/Hr)	12	(17.52*A*D*G/2000 (Based on 98% SO2 removal)	
Design Waste Rate	L	(Ton/Hr)	23	1.811*K (Based on 98% SO2 removal)	
Include Aux Power in VOM	M	(%)	1.59	(1.05e^(0.155*D+1.3))*F*G	Assume aux power is included in VOM
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000	
Limestone Cost	P	($/Ton)	30	<--- User Input	
Waste Disposal Cost	Q	($/Ton)	30	<--- User Input	default value
Aux Power Cost	R	($/kWh)	0.06	<--- User Input	default value
Makeup Water Cost	S	($/1000[gal])	1	<--- User Input	default value
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)	default value
Elevation adjustment if > 500 Feet		(feet)	0	<--- User Input (no entry needed if less than 500 feet)	Default value - check elevation.
Interest Rate		(%)	7	<---- User Input	
Equipment Lifetime		(years)	30	<---- User Input	
Gross Load		(MW-hours)	4,295,229	<---- User Input	5 -yr avg. excluding max and min
SO2 Emission Baseline		(tons/year)	30,591	<---- User Input	5 -yr avg. excluding max and min

3.2.8.1 Selection of Wet FGD Cost Model Input Parameters

Below, for those input values that are different than our SDA cost model, we review the wet FGD Cost Model input values and discuss the procedures we employed in selecting them when developing the cost estimates for the individual wet FGD installations.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM wet FGD Documentation states: "The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu." As we discuss in Section 3.2.2, we have assumed a level of control equal to 98%, unless that level of control would fall below an outlet SO_2 level of 0.04 lb/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu.

Limestone Cost. Unlike the DSI and SDA cost algorithms, the wet FGD cost algorithms are fairly insensitive to the cost of the reagent – limestone. The cost algorithm default cost for delivered lime is $30/ton. We have employed a value of $40/ton based on the 4/15/16 Trinity Nelson BART analysis.

Elevation Adjustment. Our wet FGD cost model incorporates the same elevation adjustment discussed above with regard to the SDA cost model.

Wastewater Treatment. The IPM wet FGD documentation states:

> The evaluation includes a user selected option for a wastewater treatment facility. The base capital cost includes minor physical and chemical wastewater treatment. However, in the future more extensive wastewater handling may be required. Although an option for wastewater treatment is provided, no logic has been developed to accommodate the additional wastewater treatment costs.

Consequently, our cost model incorporates minor physical and chemical wastewater treatment.

3.2.8.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 11. As with our DSI and SDA cost models, the cost algorithms calculate the CECC and the FOM and VOM, and we add a calculation for the capital recovery factor, based on the interest rate and the Equipment lifetime, and use it to annualize the CECC. We exclude AFUDC and "owner's costs." To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

Table 11. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	
BMR($)	61,153,000	Base absorber island cost	
BMF($)	18,869,000	Base reagent preparation and waste recycle/handling cost	
BMW($)	9,607,000	Base reagent	
BMB($)	111,481,000	Base balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)	The cost algorithms present an additional factor, BMWW, for a possible future base wastewater treatment facility. It is currently not used, so it is not included here.
BMBA($)	111,481,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**201,110,000**	Total Base module cost including retrofit factor	
BM($/kW)	327	Base cost per kW	
Total Project Cost			
A1	20,111,000	Engineering and Construction Mnagement costs	
A2	20,111,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	20,111,000	Contractor profit and fees.	
CECC ($)	**261,443,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**425**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	13,072,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**274,515,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**447**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	27,452,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**301,967,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**491**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			The cost algorithms present additional factors, FOMWW and VOMWW, for a possible future base wastewater treatment facility. They are currently not used, so they are not included here.
FOMO ($/kW-yr)	3.09	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators	
FOMM ($/kW-yr)	4.91	Fixed O&M additional maintenance material and labor costs	
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**8.15**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.28	Variable O&M costs for limestone reagent	
VOMW ($/MWh)	0.38	Variable O&M costs for waste disposal	In the calculation, the factor of "10" results from dividing the conversion from kilo to mega (1000) by 100% , since the input for M is a percentage.
VOMP ($/MWh)	0.53	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)	
VOMM ($/MWh)	0.05	Variable O&M costs for makeup water	
VOM ($/MWh)	**1.23**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$261,443,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$21,068,751		
Variable operating costs	$3,817,787	VOM*(Gross Load)	
Fixed operating costs	$2,877,622	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$27,764,161**		
SO2 emissions reduction (tons)	10,896	J/(100%)*(SO2 emission baseline)	
$/ton	**2,548**		

3.2.8.3 Summary of Wet FGD Cost Model Results

Below in Table 12 is a summary of our wet FGD cost model results:

Table 12. Summary of Wet FGD Cost Model Results for Nelson Unit 6

wet FGD Control (%)	94.74
wet FGD SO2 Reduction (tpy)	9,628
wet FGD Capital Cost	$266,892,000
wet FGD Annualized Capital Cost	$21,507,866
wet FGD Variable Operating Cost	$3,596,879
wet FGD Fixed Operating Cost	$2,623,645
wet FGD Total Annualized Cost	$27,728,390
wet FGD Cost Effectiveness 2012 ($/ton)	$2,880
wet FGD Cost Effectiveness 2016 ($/ton)	$2,743

As with our SDA cost model results, the majority of the total annualized cost of SDA is due to the annualized capital costs. However, the annualized capital costs is much greater than the operational costs. This is due to the slightly higher capital cost of the equipment and the lower cost of reagent (limestone versus lime), in relation to SDA.

Table 13 compares the capital cost and cost effectiveness of both technologies:

Table 13. Capital cost and cost effectiveness of wet FGD versus SDA for Nelson Unit 6

Capital Cost SDA	Capital Cost Wet FGD	% Difference Capital Cost Wet FGD over SDA	SDA Cost Effectiveness 2016 ($/ton)	Wet FGD Cost Effectiveness 2016 ($/ton)	% Difference $/ton Wet FGD over SDA
$243,310,000	$266,892,000	8.8	$2,706	$2,743	1.3

The capital cost of wet FGD is higher than SDA by approximately 8.8%. However, the cost-effectiveness of wet FGD versus SDA is very close. This is mainly due to the greater level of control (98% maximum versus 95% maximum) of wet FGD over SDA, which tends to offset the additional cost of wet FGD.

3.2.9 Impact Analysis Part 1: Cost of Compliance for Switching to Lower Sulfur Coal

Regarding the cost of this switch, Entergy states that the cost of the lower sulfur coal, "is based on a cost premium of $0.50 per ton, which was provided by Entergy's fuel purchasing department." No further support for this figure was provided. Entergy uses this cost premium to calculate a cost-effectiveness for switching to lower sulfur coal of $597/ton. In an effort to confirm this estimate, EPA has developed its own cost analysis as described below.

Our analysis is based on an evaluation of a control level of 0.60 lbs/MMBtu, which should serve as a general comparison to DSI, SDA, and wet FGD. Use of coals resulting in SO_2 emissions lower than 0.60 lbs/MMBtu would impact the cost-effectiveness.

In Table 2 above, we calculate the theoretical SO_2 emissions that would result from the burning of the coal, using the reported sulfur content, from the following equation:

Equation 1

$$\% \times \frac{\quad}{\quad} \times \frac{1{,}000{,}000}{\quad} \times \frac{64 \; / \quad ^{2}}{32 \; / \quad} \times \frac{1}{100\%}$$

Where: S = sulfur

% S = percent sulfur by weight

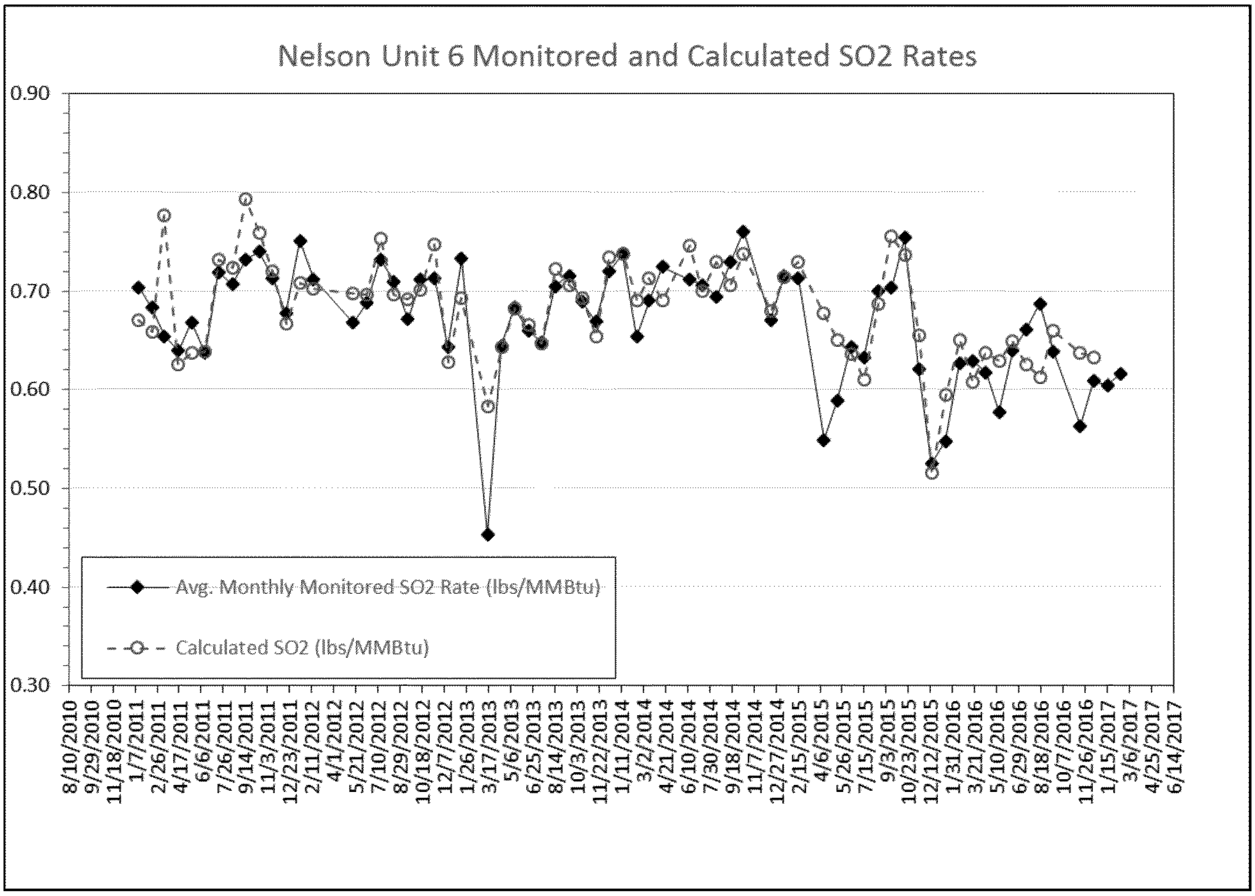
lb = pound

Btu = British Thermal Unit

Because the above equation is a theoretical calculation we tested it against Entergy's own monitoring data, as reported to us:[50]

Figure 3. Nelson Unit 6 Monitored and Calculated SO_2 Rates

[50] Monitoring data were obtained from https://ampd.epa.gov/ampd/. In this comparison, we used the information from "Page 3 Boiler Fuel Data," which we believe reflects the fuel that was burned by the Nelson facility.



The difference between these two values could be due to a number of factors, generally acknowledged in the literature, which include:

- Inadequate coal sampling including factors such as sample size, frequency, location (at the mine, train manifest, pile, blending hopper, silos, conveyor belts);
- Errors in reporting of the coal sulfur data, the heating value of the coals, and the amount of coal burned.
- Our assumption that all coal sulfur will be oxidized to SO_2 in equation (1) at the theoretical rate of 2 pounds SO_2 for every pound of S. Some of the sulfur is in fact converted to other sulfur compounds such as SO_3 that are not measured by the SO_2 CEMS.[51]
- Potential effects of the Nelson Unit 6 ESP. ESPs reduce sulfur by removing particulate matter with absorbed SO_3.[52]
- Losses of sulfur, such as pyrite, when the coal is pulverized or in bottom ash.

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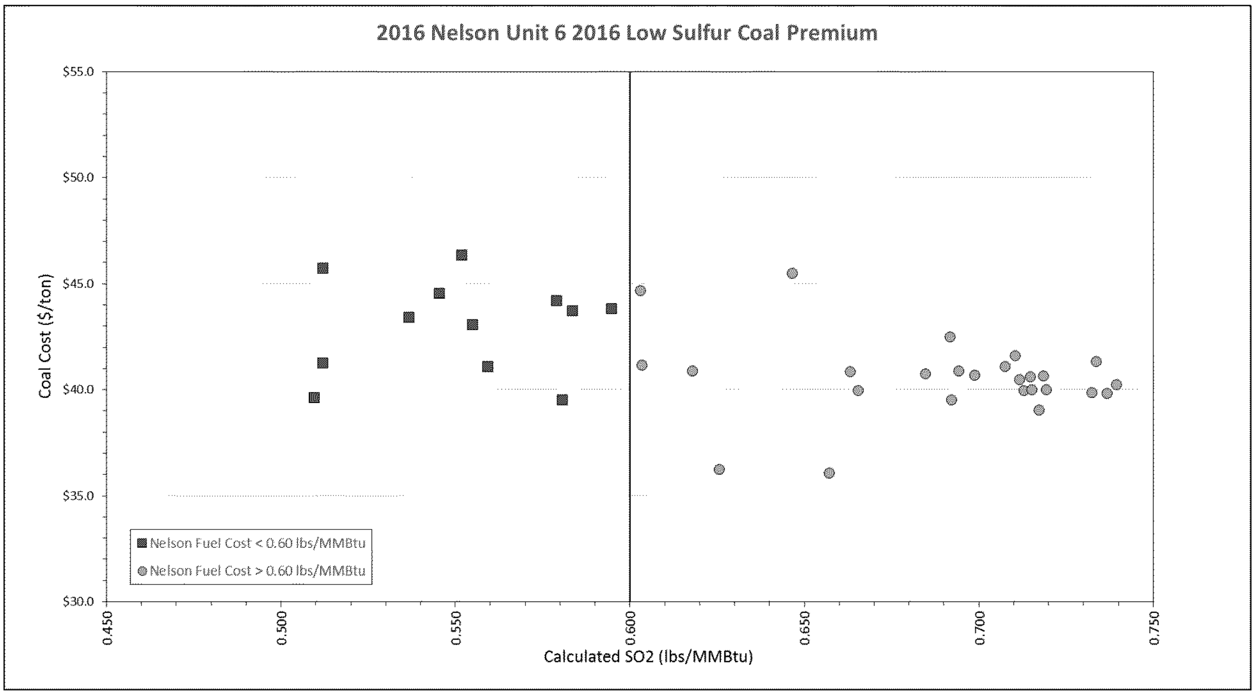
[51] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Technical Update, EPRI, March 2012.
[52] R. Hardman, et al, Estimating Sulfuric Acid Aerosol Emissions from Coal-Fired Power Plants, U. S. Department of Energy-FETC Conference on Formation, Distribution, Impact, and Fate of Sulfur Trioxide in Utility Flue Gas Streams, March 1998; R. K., Srivastava, et al, Emission of Sulfur Trioxide from Coal-Fired Power Plants, J. Air Waste Manag Assoc. 2004 Jun;54(6):750-62.

- Sulfur reported on an as-received basis rather than dry basis; the as-received sample includes moisture, which would dilute (or lower) the sulfur content.

Nevertheless, as can be seen from the above figure, there is a fairly good correspondence between the Nelson Unit 6 calculated SO_2 emissions and the actual monitored Nelson Unit 6 SO_2 emissions. We believe this validates the analysis we present below which relies on coal purchasing data.

After ordering the data in increasing sulfur content, we identified all the coal purchases in 2016 for which the calculated SO_2 emissions are below (shaded in green) and above (shaded in yellow) the 0.60 lbs/MMBtu level Entergy has selected for its low sulfur coal BART case. That information is presented below graphically:[53]

Figure 4. 2016 Nelson Unit 6 Low Sulfur Premium



Although the data is somewhat scattered, it does appear that the actual premium Entergy paid for coals that would result in a SO_2 emission limit below 0.60 lbs/MMBtu is higher than the $0.50 Entergy reports in its BART analysis. The average costs of these coals are as follows:

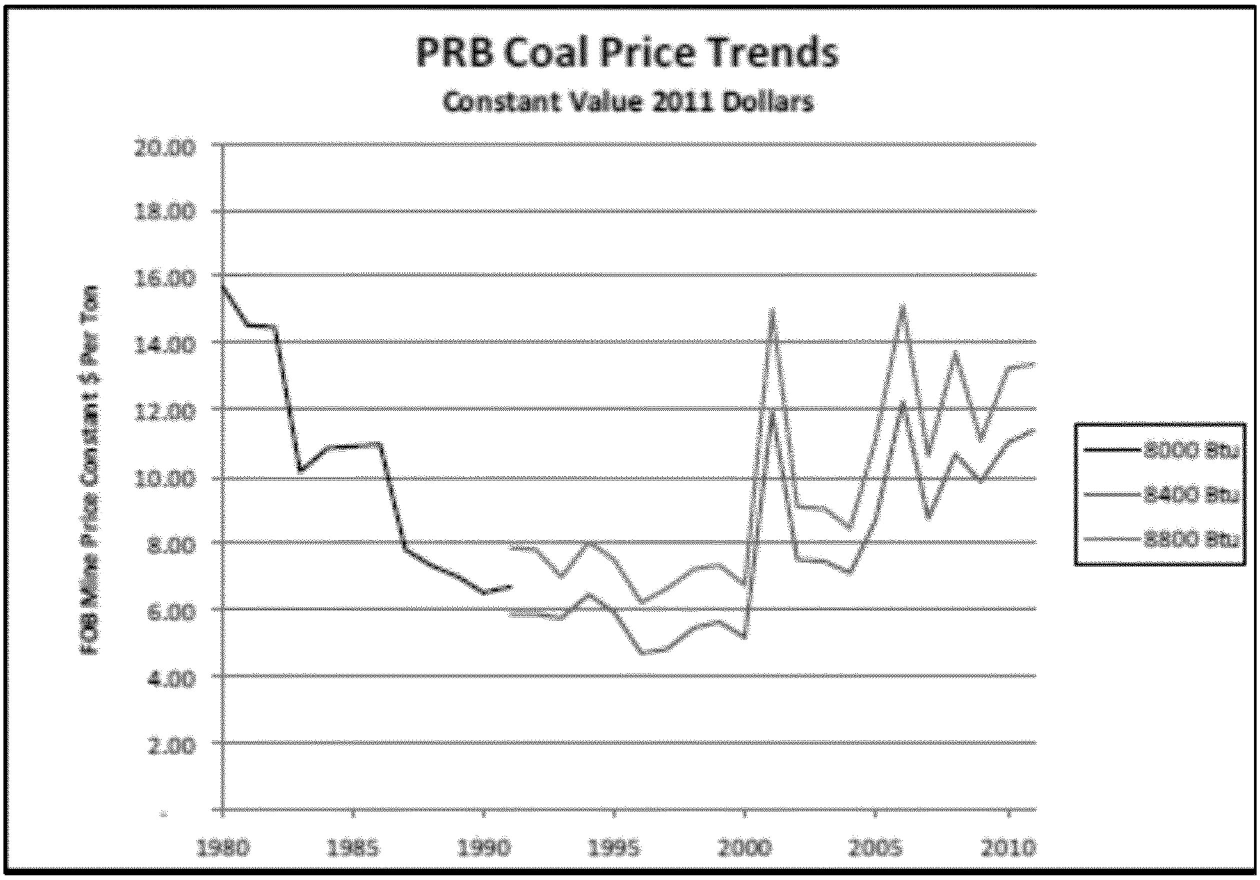
Table 14. Estimate of 2016 Entergy Low Sulfur Coal Premium

2016 Average Coal Price > 0.60 lbs/MMBtu	$43.43
2016 Average Coal Price < 0.60 lbs/MMBtu	$40.56
2016 Lower Sulfur Coal Premium	$2.48

[53] See the file, "Nelson control costs with Entergy Corrections.xlsx," Tab "EIA 923 Purchased Coal Data."

Our calculated lower sulfur coal premium of $2.48 appears to be consistent with information published by *Coal Outlook*, at least as of 2011.[54]

Figure 5. Published Price Differential for PRB Coals



Although the above figure compares the heating value of the coal (Btu), it is directly translatable to sulfur content. As in indicated by Table 2, above, the lower sulfur coals purchased by Entergy in almost all cases also convey higher heating values. Those higher heating values are captured by the generalized 8,800 Btu coal category in the above figure.

The actual premium Entergy must pay for lower sulfur coal is an important determinant in the cost-effectiveness calculation, as it is a direct multiplier. Entergy reports that cost-effectiveness, based on a $0.50/ton premium, is $597/ton. If instead, the actual premium is higher, the cost-effectiveness is multiplied accordingly. Entergy does not report how it made this calculation so we cannot duplicate it. However, below we calculate the cost-effectiveness of a lower sulfur

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[54] Referenced in the study, "Powder River Basin Coal Resource And Cost Study Campbell, Converse and Sheridan Counties, Wyoming, Big Horn, Powder River, Rosebud and Treasure Counties, Montana. Prepared for Xcel Energy by, John T. Boyd Company, Mining and Geological Consultants, Denver, Colorado. Report No. 3155.001, September 2011." See pdf 74.

coal from the same SO_2 baseline we used above in our critique of Entergy's SDA cost-effectiveness calculation (and which we use in our own cost-effectiveness calculations) to illustrate the effect of the low sulfur coal premium.

We start by noting that, as Table 15 indicates, Entergy has purchased both higher and lower sulfur coals, so were we to apply a lower sulfur coal premium to the Nelson historical coal purchases in order to calculate a resulting capital cost, we must make two adjustments: (1) We must account for the amount of lower sulfur coal purchased, and, as we discuss above, (2) we must also account for the fact that lower sulfur PRB coals typically convey higher heating values. Regarding the first adjustment, below we present a tally of the amount of higher and lower sulfur coals purchased by Entergy for the Nelson Unit 6 during the baseline years. As above, this is based on the same calculated 0.60 lbs/MMBtu level Entergy has selected for its low sulfur BART case.

Table 15. Nelson Unit 6 Higher and Lower Sulfur Coal Purchases in the Baseline Years

	Baseline Years		
	2013	2014	2016
Total Fuel Purchased (tons)	1,962,663	1,528,286	1,457,784
Total Fuel Purchased above 0.60 lbs/MMBtu (tons)	1,479,148	1,331,841	1,080,360
Total Fuel Purchased below 0.60 lbs/MMBtu (tons)	483,515	196,445	377,424
Fraction Fuel Purchased above 0.60 lbs/MMBtu	0.754	0.871	0.741

The above fractions are used in the capital cost we present below.

Regarding the second adjustment, we averaged the heating value reported by Entergy to EIA in Form 923 for the baseline years to obtain a value of 8,589 Btu/lb. Similar to the higher/lower sulfur coal fractions, we divide the resulting average heating value of 8,589 Btu/lb by 8,800 Btu/lb, resulting in a fraction that we will apply in the capital costs we present below.

Table 16. Entergy and EPA Low Sulfur Coal Cost-effectiveness Calculations

Low Sulfur Coal Cost-effectiveness Calculations					
Year	**Total Fuel Consumed (tons)**	**Annual SO_2 Averages used in baseline**	**Total Fuel Quantity Reported to EIA for EPA Baseline Years**	**Percentage Fuel Purchased above 0.60 lbs/MMBtu**	**Annual Heat Input for EPA Baseline Years**
2011	2,382,479				
2012	2,062,674				
2013	1,978,331	11,455	1,978,331	0.754	3.37E+07
2014	1,791,371	10,540	1,791,371	0.871	2.95E+07

2015	1517593				
2016	1,563,472	8,495	1,563,472	0.741	2.69E+07

Entergy's BART \$0.50 Lower Sulfur Premium & EPA SO_2 Baseline	
Calculated Additional Annual Lower Sulfur Coal Cost (using Entergy's \$0.50/ton premium)	\$684,936
SO_2 Baseline (tpy)	10,163
SO_2 Emissions assuming SO_2 Baseline Heat Input @ 0.60 lbs/MMBtu (tpy)	9,015
SO_2 Emissions Reduction @ 0.60 lbs/MMBtu (tpy)	1,149
Low Sulfur Coal Cost-effectiveness (\$/ton)	\$596

Entergy's 2016 \$2.48 Lower Sulfur Premium & EPA SO_2 Baseline	
Calculated Annual Lower Sulfur Coal Cost (using Entergy's 2016 \$2.48/ton premium)	\$3,397,281
SO_2 Baseline (tpy)	10,163
SO_2 Emissions assuming SO_2 Baseline Heat Input @ 0.60 lbs/MMBtu (tpy)	9,015
SO_2 Emissions Reduction @ 0.60 lbs/MMBtu (tpy)	1,149
Low Sulfur Coal Cost-effectiveness (\$/ton)	\$2,957

Note that in the above tables, the annual lower sulfur coal costs were calculated by multiplying each of the baseline year fuel quantities by its corresponding high/low sulfur percentage, averaging the result, and then multiplying it by the Btu fraction we discuss above. The resulting value is then multiplied by lower sulfur coal cost premiums.

3.2.10 Impact Analysis Part 1 Incremental Cost of Compliance

The BART Guidelines state:

> In addition to the average cost effectiveness of a control option, you should also calculate incremental cost effectiveness. You should consider the incremental cost effectiveness in combination with the average cost effectiveness when considering whether to eliminate a control option. The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):
>
> Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) - (Total annualized costs of next control option) ÷ (Control option annual emissions) - (Next control option annual emissions).

We have integrated this concept into our Entergy Nelson Unit 6 BART analyses by calculating the incremental cost-effectiveness of lower sulfur coal to DSI_{50}, DSI_{50} to SDA, and SDA to wet

FGD. We did not include DSI_{80} because we do not believe this technology would likely be selected, based on the cost-effectiveness of DSI_{50} and scrubbers. This information is presented below:

Table 17. Summary of SO_2 BART Incremental Cost-Effectiveness for Nelson Unit 6

Control	Control level (%)	SO_2 reduction (tpy)	2012 Capital Cost	2012 Total Annualized Cost	2016 Total Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental $/ton
Lower Sulfur Coal		1,149			$3,397,281	$2,957	
DSI	50	5,082	$17,840,000	$19,087,899	$18,180,195	$3,578	$3,759
SDA	92.11	9,361	$243,310,000	$26,597,552	$25,332,736	$2,706	$1,671
Wet FGD	94.74	9,628	$266,892,000	$27,728,390	$26,409,798	$2,743	$4,027

3.2.11 Impact Analysis Parts 2, 3, 4: Energy and Non-air Quality Environmental Impacts, and Remaining Useful Life

Regarding the analysis of energy impacts, the BART Guidelines advise, "You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits."[55] As discussed above in our cost analyses for DSI, SDA, and wet FGD, our cost model allows for the inclusion or exclusion of the cost of the additional auxiliary power required for the pollution controls we considered to be included in the variable operating costs. We chose to include this additional auxiliary power in these cases. There is no auxiliary power requirement associated with switching to a lower sulfur coal. Consequently, we believe that any energy impacts of compliance have been adequately considered in our analyses.

Regarding the analysis of non-air quality environmental impacts, the BART Guidelines advise:[56]

> Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when

[55] 70 FR 39104, 39168 (July 6, 2005) [40 CFR Part 51, App. Y].
[56] *Id.* At 39169.

> the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

Two of the SO_2 control technologies we considered in our analysis – DSI and scrubbers – are in wide use in the coal-fired electricity generation industry. Both technologies add spent reagent to the waste stream already generated by the facilities we analyzed, but do not present any significant or unusual environmental impacts. As discussed below in our cost analyses for DSI and SDA SO_2 scrubbers, our cost model includes waste disposal costs in the variable operating costs. There are no non-air quality environmental impacts associated with switching to a lower sulfur coal. Consequently, we believe any non-air quality environmental impacts have been adequately considered in our analyses.

Regarding the remaining useful life, the BART Guidelines advise:[57]

> You may decide to treat the requirement to consider the source's ''remaining useful life'' of the source for BART determinations as one element of the overall cost analysis. The ''remaining useful life'' of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's OAQPS Control Cost Manual require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

We are unaware that the Nelson Unit 6 has entered into an enforceable document to shut down that unit earlier. In the DSI, SDA, wet FGD, and scrubber upgrades sections above, we have provided our reasoning why we believe that a 30 year equipment life for DSI, scrubber retrofits, and scrubber upgrades is appropriate.

As discussed above, we see no energy and non-air quality environmental impacts, or remaining useful life considerations for switching to a lower sulfur coal.

[57] 70 FR 39104, 39169 (July 6, 2005) [40 CFR Part 51, App. Y].